CASE RESOURCES INC.

2001 Annual Report

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Annual and Special Meeting

The Annual and Special Meeting of shareholders of the Corporation will be held on May 28, 2002 at 2:00pm in the Viking Room at the Calgary Petroleum Club, 319-5th Avenue S.W., Calgary, Alberta.

Abbreviations

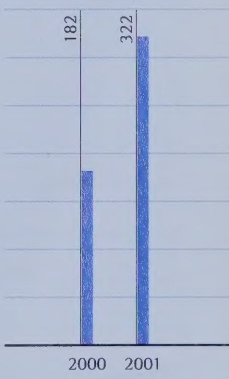
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
bbl	barrels
bbl/d	barrels per day
mbbl	thousands of barrels
boe	barrels of oil equivalent (6mcf = 1 boe)
boe/d	barrels of oil equivalent per day
mboe	thousands of boe
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
CDNX	Canadian Venture Exchange
NGL's	natural gas liquids
CAZ	Case Resources Inc.
TPI	Touchstone Petroleum Inc.
WTI	West Texas Intermediate Crude Oil

Oil Equivalent Conversion

Conversions to barrels of oil equivalent are all done on the basis of 6 mcf being equivalent to 1 barrel of oil.

Years ended December 31	2001	2000	Change
OPERATING			
Daily Average Production *(before royalties)*			
Light Oil and Natural Gas Liquids – barrels	152	153	0%
Heavy Oil – barrels	147	n/a	
Natural Gas – thousands of cubic feet	138	177	-22%
Total – barrels of oil equivalent *(6:1)*	322	182	77%
Average Sales Price			
Light Oil and Natural Gas Liquids – per barrel	$ 36.67	$ 43.04	-15%
Heavy Oil – per barrel	$ 22.23	n/a	
Natural Gas – per thousand cubic feet	$ 5.24	$ 4.12	27%
Total – per boe *(6:1)*	$ 29.70	$ 40.07	-26%
Proved and Probable Reserves *(before royalties)*			
Light Oil and Natural Gas Liquids – thousands of barrels	211	492	-57%
Heavy Oil – thousands of barrels	816	n/a	
Natural Gas – millions of cubic feet	182	567	-68%
Total – thousands of barrels of oil equivalent *(6:1)*	1,057	587	80%
Undeveloped Land			
Gross – acres	18,007	20,643	-13%
Net – acres	4,837	2,991	62%
NETBACKS AND COST *($ per barrel of oil equivalent @ 6:1)*			
Petroleum and natural gas sales	$ 29.70	$ 40.07	-26%
Other income	0.68	0.98	-31%
Royalties, net of ARTC	(3.32)	(6.15)	-46%
Operating expenses	(12.77)	(13.48)	-5%
Operating netback	14.29	21.42	-33%
General and administrative expense	(12.67)	(25.83)	-51%
Interest expense	(0.18)	(1.39)	-87%
Taxes	(0.57)	–	
Cash flow netback	0.87	(5.80)	115%
Depletion and depreciation	(12.95)	(10.76)	724%
Write-down of petroleum and natural gas properties	(75.76)	–	
Future income tax recovery	10.66	6.15	73%
Loss for the period	$ (77.18)	$ (10.41)	641%

Daily Average Production
(boe/d @ 6:1)



Notwithstanding the significant decline in commodity prices during 2001, Case achieved positive cash flow both for the fourth quarter and for the year 2001, versus negative cash flow in the year 2000. Further, Case exited the year 2001 with no bank debt.

Years ended December 31	2001	2000	Change
FINANCIAL			
Petroleum and Natural Gas Sales *($)*	3,489,522	2,670,235	31%
Cash Flow (Use) from Operations *($)*	102,830	(236,601)	143%
Per share – basic *($)*	0.01	(0.02)	150%
Per share – diluted *($)*	0.01	(0.02)	150%
Net Loss *($)*	(9,065,878)	(693,773)	-1207%
Per share – basic *($)*	(0.49)	(0.07)	-600%
Per share – diluted *($)*	(0.49)	(0.07)	-600%
Common Shares Outstanding *(basic and diluted)*			
End of Period	32,198,218	16,024,775	101%
Weighted Average For Period	18,567,707	9,943,734	87%
Capital Expenditures, net *($)*	8,166,387	2,025,542	303%
Working Capital (Deficiency) *($)*	(623,928)	2,255,316	-128%
Long-term Debt *($)*	NIL	97,109	-100%

TRANSACTION ACTIVITIES

- July 2001 – $2,885,000 private placement of flow-through shares
- July 2001 – $4,000,000 acquisition of 50% interest in heavy oil properties
- December 2001 – $2,564,000 private placement of common shares
- December 2001 – Executed a letter agreement for a $12,000,000 Property Acquisition

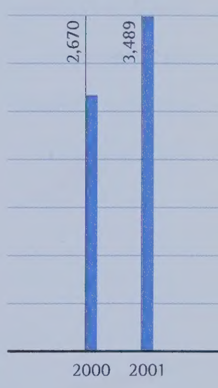
Dear shareholder,

I am pleased to report that Case made significant progress during 2001, increasing our average production during the year by 77% to 322 boe/d (6:1) and fourth quarter production by about 94% over the fourth quarter of 2000. Further, notwithstanding the significant decline in commodity prices during 2001, Case achieved positive cash flow both for the fourth quarter and for the year 2001, as compared to negative cash flow in the year 2000. Fourth quarter production averaged 432 boe/d and current production is in excess of 900 boe/d. We expect production to continue to grow at significant rates. Case exited the year 2001 with no bank debt.

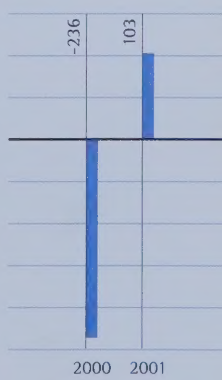
In the year 2001 our staff was extremely active in seeking out and evaluating a broad range of growth opportunities. Case bid very aggressively on assets and corporate acquisitions however we found it very difficult to complete an acquisition at prices commensurate with the reserves, drilling opportunities and initial cash flow that would be acquired. As a result of our strategy we were pleased to announce in the third quarter that we purchased a 50% working interest in certain heavy oil assets from Viracocha Energy Inc. in the West Hazel area of Saskatchewan. Case is entitled to participate with Viracocha, who is the operator of the properties, in any heavy oil opportunity that it currently has or develops in Saskatchewan. Accordingly, the acquisition is more than a mere asset purchase but rather gives us the opportunity to participate with Viracocha in the expansion of its heavy oil business. This acquisition also fulfilled our objective of achieving positive cash flow and production growth for the year 2001.

Case drilled 3 gross and 1.23 net exploration wells in 2001 with limited success, which intensified our asset acquisition strategy.

P and NG Sales
($ thousands)



Cash Flow
($ thousands)



In late November 2001 Case entered into an agreement to purchase certain Central Alberta light oil and natural gas assets for $12 million, which transaction closed in February 2002. The acquisition has increased our current production to approximately 900 boe/d. Of greater significance, we are now positioned to generate internal growth through exploitation and development drilling on our new "Haynes" property.

I anticipate significant growth in the year 2002 from our activities at Haynes and elsewhere

Haynes, discovered in the late 1960's, is a 100% working interest 40^{0} API light oil property, located 30 km east of Red Deer Alberta. Currently, Haynes has eight producing wells which were drilled using limited 2D seismic data. Haynes is contiguous with some of Case's current operated production and includes ownership interests in existing infrastructure including a major oil treatment facility, oil flow lines and a gas gathering, compression and pipeline system. Case has recently completed shooting of a 20 sq km 3D seismic program over the Haynes property and has commenced processing and interpreting the data. We anticipate re-completing six wells in the Haynes field and drilling four infill wells prior to year-end.

I would like to thank our staff and directors for having the patience to wait for the right acquisition opportunity. Thank you to our shareholders who held our shares during the year 2001, notwithstanding the downward pressure from oil prices and the economy as a whole. I anticipate significant growth in the year 2002 from our activities at Haynes and elsewhere which I trust will be reflected in the share price.

Jeff Tonken

A. Jeffery Tonken

President and Chief Executive Officer

Calgary, Alberta

April 16, 2002

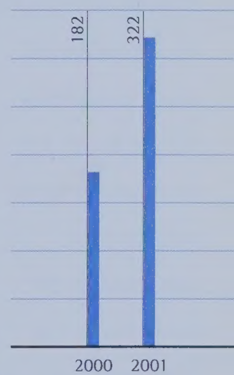
Operations

PRODUCTION

During 2001, Case produced an average of 322 boe/d consisting of 152 bbls/d of light oil, 147 bbls/d of heavy oil and 138 mcf/d of natural gas. Average production was up 77% over the prior year largely as a result of the heavy oil acquisition that occurred in July, 2001. The following table sets forth Case's production by area during 2001.

	Light Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (mcf/d)	Barrels of Oil Equivalent (Boe/d)
Acheson	59.4	–	62.4	69.8
Carrot Creek	56.6	–	–	56.6
Haynes South	32.7	–	43.8	40.0
Westhazel, Turtleford, Englishman Lake	–	146.9	–	146.9
Misc Others	3.3	–	31.8	8.6
Totals	152.0	146.9	138.0	321.9

Daily Average Production
(boe/d @ 6:1)



DRILLING ACTIVITIES

Case participated in 5 (2.5 net) heavy oil development wells during 2001, of which 4 (2.0 net) were completed as oil wells and one of which was a marginal producer and is presently shut in.

Case participated in the drilling of 3 exploration wells (1.23 net) during 2001 with disappointing results. Two of these exploration tests at Willesden Green and Mikwan were unsuccessful and the wells were abandoned. A well at Balsam (owned 18.75%) is producing at lower than expected rates. A natural gas development well (.14 net) drilled at Kyklo in Northern British Columbia encountered significant water inflow during completion and testing. The operator continues to review options for the isolation of the water source so that natural gas can be produced. The Corporation participated in 4 additional development wells (.48 net), one at Haynes South and 3 at Alderson resulting in 2 oil wells (.19 net), one gas well (.02 net) and one (.27 net) well was dry and abandoned.

PROPERTIES

Haynes Property

The Haynes field is located 30 kilometers east of Red Deer, in Township 38, Range 24 W4M, and consists of a Nisku (D2) and Leduc (D3) commingled sour light oil pool. Case has approximately 30% working interest in various lands in the southern portion of the D2A/D3A pool.

The acquisition in February 2002, of light oil and natural gas assets at Haynes in Central Alberta, has increased our current production to approximately 900 boe/d. Case is now positioned to generate internal growth through exploitation and development drilling on this new light oil property.

During the year Case operated 8 wells in the Haynes South area consisting of 1 (0.305 net) oil producer, 7 shut-in oil wells and 1 water disposal well. Case also operated a free water knockout from which clean oil was pipelined to a battery operated by Murphy Oil Company Ltd. Solution gas is conserved and compressed using a compressor in which Case held a 13% interest, which is located at the same facility.

Case's average production at Haynes South during the year was approximately 40 boe/d of which approximately 18% is attributable to solution gas. Average watercuts are approximately 92%.

As previously reported, during a workover on a water disposal well, downhole equipment became stuck in the well and Case spent a significant amount resolving this problem.

During 2001, Case participated in drilling one oil well (0.27 net) which was unsuccessful. Case did not participate in a whip stock to the north from this well which appears to have been successful although it is not yet on production. A number of development opportunities that relate to capturing by-passed oil and extending pool boundaries remain to be evaluated and pursued in the Haynes South area. Case is evaluating the drilling of one new well and is investigating the potential of recompleting one or more existing wellbores in 2002.

In November Case's ongoing acquisition review efforts identified a property purchase opportunity involving the north portion of the Haynes area. As a result, Case evaluated the opportunity and successfully bid on the property in late November 2001. In December, Case contracted to purchase the Haynes North property and other miscellaneous properties included in the sales package with an effective date of November 1, 2001 for a price of $12 million.

The acquisition of the Haynes North and other miscellaneous properties in Central Alberta was completed on February 28, 2002 for a net cost to Case of approximately $10 million after taking into account cost and revenue adjustments from the effective date, the exercise of rights of first refusal in respect of a few of the miscellaneous properties in the sales package and the immediate re-sale by Case of two of the miscellaneous properties included in the sales package.

The Haynes North property interest consists of 100% working interests in the existing 40^{o} light sour oil production from the Nisku/Leduc Reef system underlying the property.

At the time of purchase the Haynes North property was producing 323 b/d of oil and liquids and 325 mcf/d of natural gas from 8 producing wells. Case also acquired 100% ownership of the oil battery facilities and a further interest in and operatorship of the solution gas compressor. Case is currently completing the processing and interpretation of 3-D seismic that has been shot over the area.

Case expects to re-complete 6 wells and drill 4 infill wells in the Haynes North field during 2002.

Westhazel, Turtleford, Englishman Lake – Heavy Oil Properties

In July 2001, for approximately $4 million, Case acquired from Viracocha Energy Inc. a 50% interest in Viracocha's heavy oil properties primarily in the Westhazel, Turtleford and Englishman Lake areas of Saskatchewan which are located approximately 60 kilometers east of Lloydminster.

As part of this transaction Case obtained the right to participate with Viracocha in all of its future heavy oil business in Saskatchewan. In addition, Case was indemnified against operating costs in excess of $8 per barrel during the 12 months ended September 30, 2002. Viracocha was also entitled to receive up to $ 1 million of operating incentive payments if certain production related targets were achieved.

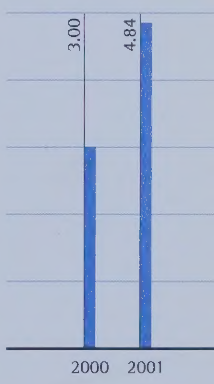
Production for these properties is 12-14^{0} gravity oil that is produced from 12 producing wells. These properties produced an average of 292 bbls/d for Case's account during the last six months of 2001 and Case's share of production during the month of March, 2002 was about 300 bbls/d.

During 2001, Case participated in the drilling of 5 (2.5 net) wells of which 4 (2.0 net) were successful oil wells but some of which have experienced severe sand production problems which results in higher operating costs and lower production than initially expected.

The aggregate production from these properties has not met Case's expectations and Case believes that no additional payments will be made by Case in respect of the $1 million of operating incentives.

Case has budgeted to participate in additional drilling of 3 development wells on these projects in 2002. Whether these projects are completed this year will be a function of the trends in heavy oil commodity prices as the year progresses and the ongoing performance of the wells drilled last year.

Land Holdings
Thousands of net acres



Acheson Property

The Acheson property was acquired in August 2000 and is located in townships 52-53, Range 25-26, on the west side of the city of Edmonton. Production is from the Basal Quartz formation at an approximate depth of 1300m. Case has 100% working interest in 2 sections of land and 2 oil batteries.

Case's current production from the area is approximately 45 boe/d of light sour crude and associated gas from 8 producing wells. Average water cuts are approximately 90%.

The main focus in this field is on improving operating efficiencies and reducing operating costs.

The majority of the wells in Acheson produce at rates of less than 3 BOPD. The wells are economic at current oil process, however, unit-operating costs are high and these wells may be uneconomic to produce if oil prices decline significantly from present levels.

Carrot Creek Property

The Carrot Creek field is located in Township 53, Range 13, 150 km west of Edmonton. Production of light sweet oil is from the Cardium GG pool in which Case has a working interest of 80%.

All producing wells in the GG pool are pipelined to a central battery which is 80% owned by Case and has testing, treating, and storage facilities. The central battery also has water injection facilities with 1 injector and 2 source water wells. The small amount of solution gas that is produced is used as fuel.

Current production from this area is approximately 44 BOPD gross (35 BOPD net) with an average watercut of approximately 96%.

Future development opportunities in Carrot Creek are limited. In 2001, one well was successfully re-stimulated and additional re-stimulation potential is being reviewed.

The unit operating costs at Carrot Creek are very high. This property may become uneconomic to produce if oil prices decline significantly from present levels.

RESERVES EVALUATION

Third Party Engineering

An independent evaluation of essentially all of Case's reserves was prepared as of December 31, 2001. Light oil and natural gas reserves were evaluated by Gilbert Lausten Jung Associates Ltd. ("GLJ"). Heavy oil reserves were evaluated by Outtrim Szabo Associates Ltd. ("Outtrim"). The reserve estimates were prepared based on a review of the reservoir and performance characteristics, as well as historical revenues and costs.

Escalated Pricing and Costs

The following table sets forth a summary of the Corporation's Reserves as at January 1, 2002 based on GLJ's forecast of commodity prices, exchange rates and inflated operating and capital costs:

GLJ Evaluation – Escalated Pricing

	Reserves Summary [1, 2]						Estimated Future Net Cash Flow Discounted at ($000's)			
	Crude Oil and NGLs (MBBL)		Natural Gas (MMCF)		BOE @6:1 (MBOE)					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	128	110	94.5	68.4	144	122	1185	1031	970	917
Proved Undeveloped	–	–	–	–	–	–	–	–	–	–
Total Proved	128	110	94.5	68.4	144	122	1185	1031	970	917
Probable	83	70	87.4	61.7	98	80	697	459	379	317
Total Proved + Probable	211	180	181.9	130.1	242	202	1882	1490	1349	1234
Established (Proved + 1/2 Probable)	170	145	138.2	99.3	193	162	1534	1261	1160	1076

1 Gross Reserves are the Corporation's interest before deduction of royalties.

2 Net Reserves are the Corporation's interest after deduction of royalties.

GLJ's forecast commodity prices, exchange rates and inflation rate is as follows:

Year	Oil WTI (US$/bbl)	Gas[1] Average (C$/mmbtu)	Exchange Rate (US$/C$)	Inflation Rate (%)
2002	20.00	3.95	0.635	1.5
2003	21.00	4.35	0.65	1.5
2004	21.00	4.45	0.67	1.5
2005	21.25	4.50	0.69	1.5
2006	21.75	4.50	0.70	1.5
2007	22.00	4.50	0.70	1.5
2008	22.25	4.50	0.70	1.5
2009	22.50	4.55	0.70	1.5
2010	23.00	4.60	0.70	1.5
2011	23.25	4.70	0.70	1.5

1 *Alberta Plant Gate*

Reserves
Proven + Probable
(000's boe @ 6:1)

The following table sets forth a summary of Outtrim's estimate of the Corporation's heavy oil reserves as at January 1, 2002 based on Outtrim's forecast of commodity prices, exchange rates and inflated operating and capital costs:

Outtrim Evaluation — Escalated Pricing

	Reserves Summary[1,2] Heavy Oil (MBBL)		Estimated Future Net Cash Flow Discounted at ($000's)			
Reserve Category	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	213	189	1712	1392	1277	1182
Proved Non-Producing	369	334	4058	1552	1127	869
Total Proved	582	523	5770	2944	2404	2051
Probable	234	207	2252	1283	1053	895
Total Proved + Probable	816	729	8022	4227	3457	2946
Established (Proved + 1/2 Probable)	699	626	6896	3586	2931	2499

1 *Gross Reserves are the Corporation's interest before deduction of royalties.*

2 *Net Reserves are the Corporation's interest after deduction of royalties.*

Outtrim's forecast commodity prices, exchange rates and inflation rate is as follows:

Year	Oil WTI (US$/bbl)	Exchange Rate (US$/C$)	Inflation Rate (%)
2002	20.50	0.64	1.5
2003	20.81	0.65	1.5
2004	21.12	0.66	1.5
2005	21.44	0.67	1.5
2006	21.76	0.67	1.5
2007	22.08	0.67	1.5
2008	22.42	0.67	1.5
2009	22.75	0.67	1.5
2010	23.09	0.67	1.5
2011	23.44	0.67	1.5

1 *Alberta Plant Gate*

Constant Pricing and Costs

The following table sets forth a Summary of GLJ's estimate of the Corporation's light oil and natural gas Reserves at January 1, 2002 based on constant Edmonton Par prices of $29.19 Cdn/bbl for oil and liquids and an average plant gate natural gas price of $3.32 and no inflation for operating and equipment costs:

GLJ Evaluation – Constant Pricing

	Reserves Summary [1, 2]						Estimated Future Net Cash Flow Discounted at ($000's)			
	Crude Oil and NGLs (MBBL)		Natural Gas (MMCF)		BOE @ 6:1 (MBOE)					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	127	109	90.9	65.5	142	120	1030	892	837	790
Proved Undeveloped	–	–	–	–	–	–	–	–	–	–
Total Proved	127	109	90.9	65.5	142	120	1030	892	837	790
Probable	88	75	87.4	61.7	103	86	639	411	336	276
Total Proved + Probable	215	184	178.3	127.2	245	206	1669	1303	1173	1066
Established (Proved + 1/2 Probable)	171	147	134.6	96.4	194	163	1350	1098	1005	928

1 *Gross Reserves are the Corporation's interest before deduction of royalties.*

2 *Net Reserves are the Corporation's interest after deduction of royalties*

The following table sets forth a Summary of Outtrim's estimate of the Corporation's heavy oil reserves at January 1, 2002 based on constant wellhead prices of Cdn $12.69/bbl for oil and no inflation for operating and equipment costs:

Outtrim Evaluation – Constant Pricing

	Reserves Summary[1, 2] Heavy Oil (MBBL)		Estimated Future Net Cash Flow Discounted at ($000's)			
Reserve Category	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	213	190	637	552	520	491
Proved Non-Producing	369	333	936	415	315	252
Total Proved	582	523	1573	967	835	743
Probable	234	209	604	366	306	264
Total Proved + Probable	816	733	2177	1333	1141	1007
Established (Proved + 1/2 Probable)	699	628	1875	1150	988	875

1 Gross Reserves are the Corporation's interest before deduction of royalties.

2 Net Reserves are the Corporation's interest after deduction of royalties

Gross Reserves Reconciliation

The following table sets forth the reconciliation of Case's gross reserves as at January 1, 2002.

Reserves Reconciliation

	Crude Oil and NGLs (MBBL)		Heavy Oil (MBBL)		Natural Gas (MMCF)		Total (MBOE @ 6:1)		
	Proved	Probable	Proved	Probable	Proved	Probable	Proved	Probable	Established
Reserves at January 1, 2001	269	223	–	–	372	195	331	256	459
Acquisitions and Divestments	–	–	411	224	–	–	411	224	523
Drilling and Development	–	–	225	10	–	–	225	10	230
Production	(56)		(54)		(50)		(118)	–	(118)
Revisions:									
From Pricing and Cost Changes	–	–	–	–	–	–	–	–	–
Other Revisions	(85)	(140)	–	–	(227)	(107)	(123)	(157)	(202)
Reserves at January 1, 2002	128	83	582	234	95	87	726	332	892

The following discussion and analysis is management's assessment of Case's historical financial and operating results and should be read in conjunction with the audited comparative financial statements of the Corporation for the year ended December 31, 2001, together with the notes thereto. Readers should be aware that the following discussion and analysis relates in part to the 2000 fiscal year.

This Annual Report includes forward-looking statements respecting the Corporation's strategies, future operations and expected financial results and discusses issues, risks and uncertainties that can be expected to impact on future operations and expected financial results. Actual future results may differ materially from those described in such forward-looking statements as a result of the impact of such issues, risks and uncertainties which the Corporation may not be able to control. The reader is therefore cautioned not to place undue reliance on such forward-looking statements.

FINANCIAL HIGHLIGHTS

The following table sets forth a summary of the financial highlights of the Corporation for the years ended December 31, 2001 and 2000.

Years ended December 31 *($, except per share and production amounts)*	**2001**	2000
Petroleum and natural gas sales	**3,489,522**	2,670,235
Total revenues, net of royalties	**3,179,788**	2,325,862
Cash flow (use) from operations	**102,830**	(236,601)
Basic and diluted per share	**0.01**	(0.02)
Net loss	**(9,065,878)**	(693,773)
Basic and diluted per share	**(0.49)**	(0.07)
Capital expenditures, net	**8,166,387**	2,025,542
Working capital surplus (deficiency)	**(623,928)**	2,255,316
Shareholders' equity	**1,385,849**	6,422,178
Average daily production *(boe at 6:1)*	**322**	182
Common shares outstanding, end of period		
Basic and diluted	**32,198,218**	16,024,775
Weighted average common shares outstanding		
Basic and diluted	**18,567,707**	9,943,734

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

The financial results of the Corporation have been and will continue to be significantly affected by a number of corporate financing and property transactions that were closed in 2000 and 2001. These transactions are summarized below:

1. In February of 2000, the Corporation issued 140,000 common shares and 70,000 warrants exercisable at $0.60 per share for a price of $0.50 per unit for gross proceeds of $70,000.

2. In August of 2000, the Corporation purchased its Acheson property for $660,900 which consisted at the time of numerous non-producing well bores. Currently Acheson produces approximately 45 boe per day.

3. In August of 2000, the Corporation issued 1,160,000 flow-through common shares at a price of $0.50 per common share for gross proceeds of $580,000.
4. In October of 2000, the Corporation issued 4,000,000 common shares at a price of $0.75 per common share for gross proceeds of $3,000,000.
5. In December of 2000, the Corporation sold its working interest in the Eureka property in Saskatchewan for proceeds of approximately $254,000.
6. In December of 2000, the Corporation issued 2,000,000 flow-through common shares at a price of $1.00 per common share for gross proceeds of $2,000,000.
7. On July 11, 2001, the Corporation issued by private placement 3,205,443 flow-through common shares at a price of $0.90 per share for gross proceeds of $2,885,000 (net proceeds of $2,713,987 after financial advisory fees of $154,245 and related costs). The directors and officers of Case subscribed for approximately one third of these common shares.
8. In July 2001, the Corporation acquired from Viracocha Energy Inc. a 50% undivided interest in certain heavy oil properties in the Westhazel, Turtleford and other nearby areas of Saskatchewan for a purchase price of approximately $4 million. Viracocha, as the operator of the properties, is entitled to receive an incentive of up to $1 million if certain operational and production goals are achieved. Management does not expect Viracocha to achieve the threshholds necessary to obtain the incentive payments. Case is also entitled to participate with Viracocha in its heavy oil opportunities that it currently has or develops in Saskatchewan.
9. On December 14, 2001, the Corporation completed a private placement of 12,823,000 common shares at a price of $0.20 per share for gross proceeds of $2,564,600 (net proceeds of $2,561,185 after related costs).
10. On February 28, 2002, the Corporation closed a $12 million acquisition of light oil and natural gas producing properties in Central Alberta. The acquisition had an effective date of November 1, 2001 for the purpose of determining the final purchase price. In conjunction with this acquisition some miscellaneous interests were removed from the acquisition by the exercise of rights of first refusal by third parties. Also, the Corporation concurrently resold some additional miscellaneous properties acquired in this transaction. As a result of the above, the Corporation's net acquisition price was approximately $10 million. In order to finance the acquisition, the Corporation issued 24,999,999 common shares at $0.30 per share pursuant to a private placement on February 14, 2002 for gross proceeds of $7,500,000 (net proceeds of approximately $7,000,000 after commission of $375,000 and related costs (See Note 6(l) to the Financial Statements) and increased its revolving production loan facility (see Note 5 to the Financial Statements).

LIQUIDITY

The Corporation had a working capital deficit of $623,928 and no bank debt at December 31, 2001. This is a substantial decrease from the prior year working capital surplus of $2,255,316. The decrease is a direct result of the increased capital spending program during the second half of 2001. This included the acquisition and development of the heavy oil properties and the expenditure of funds to satisfy flow-through share expenditure commitments.

The Corporation has traditionally financed its oil and gas operations primarily through the reinvestment of the Corporation's cash flow from operations, proceeds from long-term debt and equity financings. The Corporation expects to be able to continue to raise additional equity and debt financing sufficient to meet both its short-term and long-term growth requirements in the current positive environment. The Corporation expects to have sufficient cash flow and available credit to complete its budgeted capital expenditure program for 2002. The Corporation is expecting an increase in its credit facility based on the expected results of its capital expenditure program. This increase is expected to provide the funds necessary to complete the capital expenditure program. The Corporation intends to dispose of some non-core properties which will provide additional working capital.

The main components of the budgeted capital expenditure program include, the Central Alberta property acquisition, 3D seismic over Haynes, 6 recompletions at Haynes, the drilling, completion and equipping of 4 oil wells at Haynes, and the drilling, completion and equipping of 3 heavy oil wells in Saskatchewan. If the Corporation is unable to obtain the necessary increase in its credit facility, it will have to either issue equity or dispose of non-core properties in order to maintain its budgeted capital expenditure program or reduce/delay its capital expenditures until the necessary cash flow is generated to continue the program.

The Corporation has not budgeted for any other acquisitions for 2002. Management is confident that in the current environment, should an attractive acquisition opportunity arise the Corporation would be able to raise sufficient equity and debt to allow it to pursue that opportunity.

The major risk factors affecting the Corporation's liquidity are commodity prices for light oil, natural gas and heavy oil, the uncertainty of achieving planned production from the expenditure of capital on development and exploration projects and the ability to raise new equity. The commodity price environment is currently very strong with WTI spot oil prices around US$25.00. However, the commodity price is unpredictable and therefore the Corporation may from time to time fix the price for future periods on some of its production. See the heading under Management's Discussion and Analysis entitled "Petroleum and Natural Gas Sales" and note 9 to the financial statements for details of the current commitments.

Should the commodity price decline to below WTI US$20.00 for an extended period of time, the Corporation would not be able to fund its entire capital program from its cash flows and existing credit lines and it would therefore be required to reduce its budgeted capital spending program for 2002, raise additional equity or dispose of non-core properties. The Corporation is presently planning to dispose of its non-core properties.

The Corporation manages the risks associated with its development and exploration projects by maintaining a highly qualified technical and experienced operations team to identify and then evaluate the Corporation's opportunities. The Corporation's 2002 capital spending is primarily focussed on the newly acquired Haynes property with approximately 80% of the 2002 capital budget being budgeted for that area (including the acquisition price). Should the capital spending on this property not produce anticipated results, management will have to review the remaining capital expenditure program to ensure the costs of the projects it proceeds with will be within the financial resources available from its cash flow, debt capacity, proceeds, if any, from disposition of non-core properties, and additional financing capability at that time.

CASH FLOW FROM OPERATIONS

The Corporation's cash flow from operations of $102,830 during the year ended December 31, 2001 is an increase of 143% over the cash used in operations of $236,601 in 2000. This increase in cash flow was due primarily to the heavy oil acquisition in July 2001. The cash flow from the property directly impacted the Corporation's cash flow because the addition of these properties generated material revenues but had minimal effect on the Corporation's staffing and general and administrative expenses. Management expects that the Corporation will have a substantial increase in cash flow from operations in 2002 as a result of the recent strengthening of the commodity prices, the cash flow impact of the recent acquisition of the Central Alberta properties in February 2002 and the full year impact of the production from the heavy oil properties acquired in July 2001.

The two key factors currently influencing the Corporation's cash flow from operations are the level of commodity production and the commodity price. Although the impact on the Corporation of interruptions in production from individual wells is less than would have been the case during 2000, the Corporation still relies on some relatively high volume oil wells and should an uncontrollable event occur which adversely affects any of those high volume wells, it would significantly affect cash flow. The Corporation expects that its cash flow from operations for the year ended December 31, 2002 together with anticipated increases in our credit facility will be sufficient to fund our budgeted capital program for 2002.

SENSITIVITY ANALYSIS

The following table set forth management's estimate of the sensitivity of expected cash flow to be generated by the Corporation during the period January 1, 2002 through December 31, 2002 due to the foregoing and other factors. The calculated sensitivities are based on the Corporation's 2002 budget approved by the Board of Director's and includes the Central Alberta acquisition in February 2002. The budget also includes a significant capital expenditure program on the newly acquired properties and the heavy oil properties. The 2002 budget does not include any other acquisitions.

Factor	2001 Budget		Variance in Factor		Variance in Cash Flow	
WTI oil price	$US	22.00	US	$1.00/bbl	CDN$	326,000
Natural gas spot price	$CDN	4.25	CDN	$0.10/mcf	CDN$	61,000
Lloyd Blend Differential	$US	7.00	US	$1.00/bbl	CDN$	69,000
CDN$/US$		1.5625	CDN	$0.01	CDN$	46,000
Prime rate		5.13%		1.0%	CDN$	68,000

BANK DEBT

As a result of the equity financing in December 2001 described elsewhere, the Corporation had no bank debt at December 31, 2001, however, the Corporation was in a working capital deficit of $623,928. The Corporation currently has in place a $5,975,000 demand revolving operating credit facility with a major lending institution. Outstanding indebtedness bears interest at the institution's prime lending rate plus 1%. The Corporation has already drawn down a substantial portion of this credit facility in order to finance the recent acquisition of the Central Alberta properties and to fund capital projects. At March 31, 2002 the amount outstanding under this credit facility was approximately $4.2 million.

Management's intent is to work closely with its credit facility provider to increase the credit facility based upon the reserves currently owned and the anticipated results of our capital expenditure program for 2002. The Corporation intends to maintain some debt leverage while leaving some unused debt capacity to maintain operational and financial flexibility to enable us to capitalize on opportunities that may materialize.

EQUITY ISSUES

The following table summarizes the common shares issued during 2001 and 2000.

	Common Shares
Balance at December 31, 1999	8,374,775
Exercise of Options	350,000
Private Placements	7,300,000
Balance at December 31, 2000	16,024,775
Exercise of Options and Warrants	145,000
Private Placements	16,028,443
Balance at December 31, 2001	32,198,218

For details of the equity issues see Note 6 of the December 31, 2001 Financial Statements.

RESULTS OF OPERATIONS

Petroleum and Natural Gas Sales

Petroleum and natural gas sales for the year ended December 31, 2001 were $3,489,522, which represents a 31% increase over the $2,670,235 realized in 2000. This increase in sales is primarily a result of the heavy oil acquisition in July 2001 and a full year of sales from the Acheson property which was acquired in August 2000. Average daily production for the year ended December 31, 2001 was 322 boe/d as compared to 182 boe/d realized for the same period in 2000. The increase in sales revenues as a result of increased production was offset somewhat by lower oil prices realized in 2001. The Corporation's average sales price for the year ended December 31, 2001 was $29.70 per boe as compared to $40.07 per boe received in 2000. Approximately 47% of the Corporation's production was light oil and 46% was heavy oil during the 2001 fiscal year.

The following table sets forth Case's average production and prices received for its two most recently completed fiscal periods:

Years Ended December 31	**2001**	2000
Light oil and natural gas liquids		
Average daily production (bbl)	**152**	153
Average sales price ($per bbl)	**36.67**	43.04
Heavy oil		
Average daily production (bbl)	**147**	N/A
Average sales price ($per bbl)	**22.23**	N/A
Natural gas		
Average daily production (mcf)	**138**	177
Average sales price ($per mcf)	**5.24**	4.12
Average daily production (boe)	**322**	182
Average sales price ($per boe)	**29.70**	40.07

The price the Corporation receives for its crude oil depends on a number of factors, including U.S. dollar oil prices, the U.S./Canadian dollar exchange rate, and transportation and product quality differentials. Case regularly considers managing the risk associated with fluctuating U.S. dollar oil prices and the U.S./Canadian dollar exchange rate. In order to manage the risk the Corporation may enter into forward sale contracts, U.S. dollar oil price hedges and/or forward foreign exchange contracts.

From January 1 to December 31, 2001 the Corporation sold forward 150 bbls/d of heavy oil at a WTI price of Cdn $43.99 and at a Lloyd Blend at Hardisty differential of US$9.00. See note 9 to the December 31, 2001 financial statements for the forward sales relating to 2002. The Corporation has entered into a forward sale for the 2003 calendar year which fixes a WTI price of Cdn $37.32 and a Lloyd Blend at Hardisty differential of US$7.80 on a volume of 100 bbls/d of heavy oil.

Royalties and ARTC

Royalties, net of ARTC, in the year ended December 31, 2001 were $390,194 which represents a 5.0% decrease from the $409,896 incurred in 2000. This decrease is a result of the heavy oil acquisition, which has much lower royalty rates than conventional wells as a result of a lower maximum royalty rate and royalty holidays applicable to new wells. Also during the year the wellhead prices received for both light and heavy oil were lower than in 2000.

Operating costs

Operating costs in the year ended December 31, 2001 were $1,500,579, which represents a 67% increase over the $898,481 incurred in 2000. This increase is primarily a result of the heavy oil acquisition and a full year of operating costs for our Acheson property which was purchased in August, 2000. On a per unit basis, operating costs decreased approximately 5% in 2001 to $12.77 per boe from $13.48 per boe in 2000. The lower unit costs were primarily a result of the Corporation's acquisition of the heavy oil properties, which have had lower operating costs than our conventional oil properties. Due to natural declines, our conventional properties all had higher operating costs per boe than in 2000, but this has been more than offset by the low operating costs on our heavy oil properties. Although the Corporation's heavy oil properties have low operating costs, these heavy oil properties have experienced high maintenance capital expenditures which may continue through 2002.

General and Administrative Expense

General and administrative costs in the year ended December 31, 2001 were $1,488,163, which represents a 14% decrease over the $1,721,314 incurred in 2000. If you remove the $150,010 write-down of long-term note receivable in 2000 which was included in general and administrative expenses then the decrease is only 5% from 2000 to 2001. This decrease is due primarily to the incurrence in 2000 of one time severance costs associated with the management reorganization in September 2000. On a per unit basis, general and administrative costs decreased approximately 51% in the current period to $12.67 per boe from $25.83 per boe in 2000, primarily as a result of increased production due to the heavy oil acquisition. The components of general and administrative expense are as follows:

General and Administrative Expense

Years Ended December 31 (thousands)	2001 $	2000 $
Salaries and benefits	1,032	896
Office rent	195	176
Consultants, audit and legal	116	413
Computer software and hardware maintenance	85	77
Corporate development expense	34	6
Bank charges	30	12
Write-down of long-term account receivable	0	150
Remaining	304	195
General and administrative expense gross	1,796	1,925
Overhead recoveries	(175)	(93)
Capitalized overhead	(133)	(111)
General and administrative expense net	1,488	1,721

Interest Expense

Interest expense in the year ended December 31, 2001 was $21,016. The prior year interest expense was $92,678. This decrease is due primarily to Case being in a cash position in the beginning of 2001 due to the December 2000 equity issue and the fact that Case did not utilize its credit facility until July 2001 when it purchased the heavy oil properties. The Corporation expects the interest charges to be significantly higher in 2002 due to the recent acquisition of Central Alberta properties and the development capital being expended on those properties.

Depletion and Depreciation Expense

Depletion and depreciation expense in the year ended December 31, 2001 was $1,398,581, which represents a 113% increase over the $655,560 incurred in 2000. This increase is due primarily to the acquisition of the heavy oil properties and the increased capital costs associated with these properties. On a per boe basis depletion and depreciation increased in 2001 from $9.84 per boe in 2000 to $11.91 per boe primarily due to the increased capital cost of its 2001 capital program without a corresponding increase in reserves associated with that capital spending.

Provision for future site restoration costs

Site restoration expense in the year ended December 31, 2001 was $122,000, which represents a 99% increase over the $61,249 incurred in 2000. The increase is due primarily to the acquisition of heavy oil properties in July 2001 and the associated abandonment liabilities. On a per boe basis the amounts are comparable at $1.04 per boe for 2001 and $0.92 per boe for 2000.

Write-Down of Petroleum and Natural Gas Properties

The Corporation follows the full cost method of accounting that requires the Corporation to apply a quarterly ceiling test to ensure that capitalized costs do not exceed the estimated value of future net revenues from the production of proved reserves less certain indirect costs associated with such production.

The Corporation conducted an interim ceiling test calculation at September 30, 2001 for the fourth quarter. As a result of a further significant deterioration in product prices, the sales prices, in Canadian dollars, at the wellhead used for the ceiling test were the Corporation's September 2001 average prices of $36.27 per barrel for light oil, $18.66 per barrel for heavy oil and $2.30 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by $5,100,000 for the quarter ended September 30, 2001.

The Corporation conducted a further ceiling test calculation at December 31, 2001 for the fourth quarter. As a result of a further significant decline in product prices from the prior quarter, the sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $27.27 per barrel for light oil, $12.69 per barrel for heavy oil and $3.32 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by a further $3,800,000 for the quarter ended December 31, 2001.

The total write-down of petroleum and natural gas properties for the year ended December 31, 2001 is $8,900,000.

Taxes

The Corporation did not pay any income taxes or capital taxes in the twelve-month period ending December 31, 2001 or 2000. However the Corporation was required to pay cash taxes under Part XII.6 of the *Income Tax Act*. In the current year the Corporation has paid $67,200 (2000 - $Nil) in current taxes relating to Part XII.6 tax. Part XII.6 tax is calculated based upon when previously renounced resource expenditures are actually incurred by the Corporation.

The Corporation recorded a future income tax recovery of $1,251,873 (2000 - $409,647) in its 2001 fiscal year, to reduce its future tax liability to $NIL which resulted from incurring expenditures during the year that had been previously renounced to flow-through share subscribers in accordance with current tax legislation. The Corporation has the required amount of tax deductions available to it to be able to reduce the liability (resulting from the renounced expenditures) to $NIL. The Corporation has decided not to record the benefits of these future tax deductions as a future income tax benefit on its balance sheet.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

The Corporation incurred a loss of $9,065,878 in the year ended December 31, 2001 compared to a loss of $693,773 realized in 2000. Most of this loss ($8,900,000) results from the ceiling test write-down described above. This write down of assets reflects the impact of the Corporation's expenditure of

capital during the year for both operations and acquisitions without adding sufficient reserve values for ceiling test purposes and the impact of the low commodity prices for both light oil and heavy oil which prevailed in the month of December, 2001 which is the relevant pricing month for ceiling test purposes. Management believes that the recent Central Alberta property acquisition will provide a quality asset base from which the Corporation will be able to grow its reserves in the next two years at a capital cost which will more than justify the carrying cost of its assets.

The remaining loss for 2001 is attributable to the Corporation being in the early stages of its growth where the costs of its technical, operational, and management resources and technologies is disproportionate to the revenues that its assets produce. Management believes that the Corporation's strategy of incurring the costs of having these resources available to seek out, identify, evaluate and execute on attractive opportunities has been validated by the recent Central Alberta property acquisition which has added significant value to the Corporation and which has the potential to add significantly more value to the Corporation. This would not have been possible without all those resources.

Cash flow for the year ended December 31, 2001 was $102,830, an increase of 143% over the cash used in operations of $236,601 in 2000. This increase was due primarily to increased production realized in 2001 as a result of the heavy oil acquisition.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

The Corporation's capital expenditures amounted to $8,162,341 in the year ended December 31, 2001 as compared to $2,349,882 in 2000. The increase in capital expenditures in 2001 over 2000 capital expenditures reflects the purchase of the heavy oil properties and significantly more drilling activities.

The following table sets forth a summary of the Corporation's capital expenditures incurred for the years ended December 31, 2001 and 2000.

Capital Expenditures

Years Ended December 31	2001 $	2000 $
Property acquisitions	**4,048,628**	688,398
Land	**90,418**	35,961
Exploration – drilling and completions	**1,239,905**	NIL
Exploration – seismic	**121,192**	NIL
Exploration – other	**309,241**	2,453
Development – drilling and completions	**1,616,460**	969,565
Development – other	**47,511**	NIL
Well equipment and facilities	**551,956**	488,303
Capitalized general and administrative expenses	**132,730**	111,381
Corporate acquisitions	**–**	–
Total finding and on-stream costs	**8,158,041**	2,296,061
Administrative assets	**4,300**	53,821
Total Capital Expenditures	**8,162,341**	2,349,882

The following table sets forth a summary of the Corporation's capital resources for the years ended December 31, 2001 and 2000:

Capital Resources

Years Ended December 31	2001 $	2000 $
Cash flow (use) from operations	**102,830**	(236,601)
Changes in working capital	**790,040**	(507,087)
Bank debt and other long-term liabilities	**(97,109)**	(1,202,891)
Equity Issues	**5,338,922**	5,725,535
Disposition of assets	**(4,046)**	324,340
Repurchase of stock options	**(57,500)**	–
Total capital resources	**6,073,137**	4,103,296

OUTLOOK

In order for Case to grow and succeed, it must integrate its newly acquired Central Alberta properties. In the near term Case will be clearly focusing its efforts on the optimization and exploitation of its Central Alberta assets to add production, cash flow and reserves.

Case expects that the value of its assets will increase as it successfully exploits these Central Alberta properties, which will in turn allow Case to continue the process of identifying, evaluating and executing on new opportunities.

Management's Report

TO THE SHAREHOLDERS OF CASE RESOURCES INC.

The financial statements of Case Resources Inc. were prepared by management within the acceptable limits of materiality and are in accordance with accounting principles generally accepted in Canada. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the financial statements.

The financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee, consisting of a majority of non-management directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Jeff Tonken

A. Jeffery Tonken
President and Chief Executive Officer

Bruno P. Geremia
Vice President and Chief Financial Officer

March 6, 2002

Auditors' Report

TO THE SHAREHOLDERS OF CASE RESOURCES INC.
(formerly Touchstone Petroleum Inc.):

We have audited the balance sheets of Case Resources Inc. (formerly Touchstone Petroleum Inc.) as at December 31, 2001 and 2000 and the statements of loss and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Alberta

March 6, 2002

Statements of Loss and Deficit

For the Years Ended December 31,

	2001 $	2000 $
REVENUE		
Petroleum and natural gas sales	3,489,522	2,670,235
Royalties, net of ARTC	(390,194)	(409,896)
Other income	80,460	65,523
	3,179,788	2,325,862
EXPENSES		
Operating	1,500,579	898,481
General and administrative	1,488,163	1,571,304
Write-down of long-term note receivable *(Note 3)*	–	150,010
Interest	21,016	92,678
Depletion and depreciation	1,520,581	716,809
Write-down of petroleum and natural gas properties *(Note 4)*	8,900,000	–
	13,430,339	3,429,282
LOSS BEFORE TAXES	10,250,551	1,103,420
TAXES *(Note 8)*		
Current	67,200	–
Future income tax recovery	(1,251,873)	(409,647)
	(1,184,673)	(409,647)
NET LOSS	9,065,878	693,773
DEFICIT, BEGINNING OF YEAR	891,804	3,384,753
Stock option repurchase	57,500	–
Stated capital reduction *(Note 6(e))*	–	(3,186,722)
DEFICIT, END OF YEAR	10,015,182	891,804
Net loss per share - basic and diluted	$ 0.49	$ 0.07
Weighted average number of shares	18,567,707	9,943,734

Balance Sheets

As at December 31,

	2001 $	2000 $
ASSETS		
CURRENT		
Cash	23,414	2,112,618
Marketable securities	–	5,623
Accounts receivable	771,841	782,589
Deposits and prepaid expenses	307,076	335,488
	1,102,331	3,236,318
Petroleum and natural gas properties *(Note 4)*	2,263,203	4,395,397
	3,365,534	7,631,715
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	1,726,259	941,043
Current portion of long-term debt *(Note 5)*	–	39,959
	1,726,259	981,002
Long-term debt *(Note 5)*	–	97,109
Site restoration provision	253,426	131,426
	1,979,685	1,209,537
SHAREHOLDERS' EQUITY		
Share capital *(Note 6)*	11,401,031	7,313,982
Deficit	(10,015,182)	(891,804)
	1,385,849	6,422,178
	3,365,534	7,631,715

APPROVED BY THE BOARD

Larry Shaw

Jeff Tonken

Larry A. Shaw
Director

A. Jeffery Tonken
Director

Statements of Cash Flows

For the Years Ended December 31,

	2001 $	2000 $
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net loss	(9,065,878)	(693,773)
Adjustments for:		
Depletion and depreciation	1,520,581	716,809
Future income tax recovery	(1,251,873)	(409,647)
Write-down of long-term note receivable *(Note 3)*	–	150,010
Write-down of petroleum and natural gas properties *(Note 4)*	8,900,000	–
	102,830	(236,601)
Changes in non-cash working capital items from operations *(Note 10)*	790,040	(507,087)
	892,870	(743,688)
FINANCING		
Increase (decrease) to long-term account payable	–	(1,300,000)
(Decrease) increase to long-term debt *(Note 5)*	(97,109)	97,109
Issuance of share capital, net of related expenses *(Note 6)*	5,338,922	5,725,535
Stock option repurchase	(57,500)	–
	5,184,313	4,522,644
INVESTING		
Petroleum and natural gas properties and equipment	(8,162,341)	(2,349,882)
Sale of petroleum and natural gas properties and equipment	(4,046)	324,340
	(8,166,387)	(2,025,542)
NET (DECREASE) INCREASE IN CASH	(2,089,204)	1,753,414
CASH, BEGINNING OF YEAR	2,112,618	359,204
CASH, END OF YEAR	23,414	2,112,618

Notes to the Financial Statements

Years Ended December 31, 2001 and 2000

1. INCORPORATION AND NATURE OF OPERATIONS

Case Resources Inc. ("Case" or the "Corporation") was incorporated under the *Business Corporations Act* (Alberta) on March 12, 1993 as 558818 Alberta Inc. On April 13, 1993 the Corporation changed its name to Golden Regent Resources Ltd. On June 28, 1999 the Corporation changed its name to Touchstone Petroleum Inc. and on May 17, 2001 it changed its name to Case Resources Inc. Case is currently engaged in the exploration for and the development and acquisition of, petroleum and natural gas reserves in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

Petroleum and natural gas properties

The Corporation follows the full-cost method of accounting for petroleum and natural gas properties whereby all costs relating to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs may include lease acquisition costs, geological and geophysical expenses, lease rentals on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to exploration. Proceeds from the sale of properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by 20% or more.

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided on the unit-of-production basis using estimated gross (before royalties) proved oil and natural gas reserves as determined by independent reservoir engineers. Oil and natural gas reserves and production are converted, at a ratio of six thousand cubic feet of natural gas to one barrel of oil, for depletion and depreciation purposes.

The Corporation applies a ceiling test quarterly to capitalized costs to ensure that such costs do not exceed the estimated undiscounted value of future net revenues for the production of its total proved reserves, plus the cost of its undeveloped lands net of impairments. Future net revenues are calculated using year end sales prices and include an allowance for estimated future general and administrative expenses, financing costs, site restoration costs, income tax costs and development expenditures.

Estimated future site restoration and abandonment costs are provided for over the life of the total proved reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Corporation's engineers based on current costs and technology in accordance with the current legislation and industry practices. The annual charge is included in the depletion expense and actual site restoration and abandonment expenditures are applied against the accumulated provision account.

Most of the Corporation's exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

Per share amounts

Per share amounts are calculated using the weighted average number of common shares outstanding during the year. Diluted per share calculations reflect the exercise of options at the later of the date of grant of such options or the beginning of the year. The Corporation has adopted the treasury stock method of calculating diluted earnings per share, effective January 1, 2001. The adoption of this new accounting recommendation has resulted in no change to the diluted earnings per share for the current or prior year.

Future income taxes

Effective January 1, 2000, the Corporation adopted the Canadian Institute of Chartered Accountants' accounting recommendations with respect to income taxes and now follows the liability method of accounting for income taxes. The new recommendations were applied retroactively without restatement of prior year financial statements. The adoption of the new recommendations did not have any effect on the balances at January 1, 2000.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The Corporation records the carrying value of the expenditures in petroleum and natural gas properties and will also record a future income tax liability in relation to the benefits renounced with a corresponding reduction to share capital.

Stock options

The Corporation's stock based compensation arrangements are described in Note 7. No compensation expense is recognized for these arrangements when stock options are issued to employees. Consideration paid by employees on exercise of stock options is credited to share capital. If stock options are repurchased from employees, the excess of the consideration paid over the carrying amount of the stock option cancelled is charged to retained earnings (deficit).

Financial instruments

The Corporation has determined that the fair value of the financial instruments consisting of current assets, current liabilities and long term debt are not materially different from the carrying value of such instruments reported on the balance sheet. A substantial portion of the Corporation's accounts receivable are with commodity marketers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risk.

The nature of the Corporation's operations result in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Corporation may from time to time manage its exposure to these risks through the use of physical contracts or financial instruments. The Corporation is exposed to potential credit losses in the event of non-performance by counterparties to these arrangements. The Corporation tries to mitigate this risk by only dealing with credit worthy counterparties.

3. LONG-TERM NOTE RECEIVABLE

During the prior year the note receivable in the amount of $150,010 was determined to be uncollectible. Accordingly, the amount was written off in the prior year. The note receivable arose as part of the Corporation's decision to discontinue its drilling operations in Slovakia during the 1999 fiscal year.

4. CAPITAL ASSETS

		2001	
	Cost $	Accumulated Depreciation $	Net Book Value $
Petroleum and natural gas properties	13,510,538	11,302,131	2,208,407
Furniture and office equipment	68,096	13,300	54,796
	13,578,634	11,315,431	2,263,203

		2000	
	Cost $	Accumulated Depreciation $	Net Book Value $
Petroleum and natural gas properties	5,348,450	1,008,131	4,340,319
Furniture and office equipment	63,797	8,719	55,078
	5,412,247	1,016,850	4,395,397

The Company has capitalized general and administrative expenses related to exploration activities of $132,730 (2000 - $111,381).

During 2002, the Corporation is obligated to incur, under the terms of a flow-through share agreement, $1,662,558 of capital expenditures related to exploration of certain petroleum and natural gas properties.

During 2001, the total net book value of expenditures incurred, under the terms of a flow-through share agreement, without tax base is $3,194,663. These expenditures have no cost basis for income tax purposes and they are reflected as such in the computation of future income taxes (Note 6).

As at December 31, 2001 the estimated future site restoration costs to be amortized over the remaining proved reserves are $777,974 (2000 - $400,294) of which $122,000 (2000 - $61,249) has been included in depletion and depreciation expense in the current year.

In accordance with accounting principles generally accepted in Canada, the Corporation conducted an interim ceiling test calculation at September 30, 2001. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were the Corporation's September 2001 average prices of $36.27 per barrel for light oil, $18.66 per barrel for heavy oil and $2.30 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by $5,100,000 for the quarter ended September 30, 2001.

The Corporation conducted a ceiling test calculation at December 31, 2001. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $27.27 per barrel for light oil, $12.69 per barrel for heavy oil and $3.32 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by $3,800,000 for the quarter ended December 31, 2001.

The total write-down of petroleum and natural gas properties for the year ended December 31, 2001 is $8,900,000.

5. LONG-TERM DEBT

At December 31, 2001 the Corporation had a revolving production loan facility (the "facility") with a major lender. Direct borrowings under this facility bear interest at prime plus 1.25%. The security pledged for the facility consists of a demand debenture in the amount of $5,000,000 providing a floating charge over all of the Corporation's assets. No amount was drawn upon this facility at December 31, 2001.

The maximum amount that can be drawn upon this facility is determined by the lender from time to time after assessing the Corporation's total proved reserves. The Corporation is subject to an annual review in May of each year. At December 31, 2001 the maximum amount available under this facility was $2,375,000 based on the Corporation's then current engineering report and the lender's oil and natural gas price forecasts. The facility has been drawn upon subsequent to December 31, 2001.

Subsequent to year end, the facility has been amended in connection with the Corporation's acquisition of certain oil and natural gas properties on February 28, 2002. The security pledged for the facility now consists of a demand debenture in the amount of $20,000,000 providing a floating charge over all of the Corporation's assets. Direct borrowings under the facility now bear interest at prime plus 1.0%. The maximum amount available under this facility is currently $5,975,000. A portion of this facility has been drawn upon subsequent to December 31, 2001 to fund ongoing operations and to fund the acquisition of certain oil and natural gas properties (see Note 11).

Pursuant to a security agreement dated August 4, 2000 the Corporation granted security on its Acheson properties to certain creditors in the amount of approximately $145,000, relating to trade payables the Corporation assumed in connection with the acquisition of its Acheson properties. The Corporation is required to pay a minimum of $4,000 per month and a maximum of 10% of the net operating income

less capital from the Acheson property. As at December 31, 2001 the amount owing in relation to this security agreement was $Nil (2000 - $137,068, of which $39,959 was classified as current). The outstanding balance of this indebtedness was ultimately discharged in March of 2001 for a payment of $120,000.

6. SHARE CAPITAL

(a) Authorized:

Unlimited number of Common Voting Shares without nominal or par value
Unlimited number of First Preferred Shares
Unlimited number of Second Preferred Shares

The First and Second Preferred Shares may be issued in one or more series and the directors are authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series.

(b) Issued:

	Number of Common Shares	Amount $
Balance, December 31, 1999	8,374,775	5,184,816
Shares issued on private placement, net *(Note 6(c))*	140,000	70,000
Shares issued on private placement, net *(Note 6(d))*	1,160,000	553,249
Stated capital reduction *(Note 6(e))*	–	(3,186,722)
Shares issued on private placement, net *(Note 6(f))*	4,000,000	2,993,118
Shares issued on private placement, net *(Note 6(g))*	2,000,000	1,996,943
Shares issued on exercise of options *(Note 7)*	350,000	112,225
Future income tax liability on flow-through share expenditures incurred, under the terms of a flow-through share agreement,	–	(426,018)
Future income tax benefit on share issue costs	–	16,371
Balance, December 31, 2000	16,024,775	7,313,982
Shares issued on exercise of warrants *(Note 6(h))*	70,000	42,000
Shares issued on exercise of options *(Note 6(i))*	75,000	21,750
Shares issued on private placement, net *(Note 6(j))*	3,205,443	2,713,987
Shares issued on private placement, net *(Note 6(k))*	12,823,000	2,561,185
Future income tax liability on flow-through share expenditures incurred	–	(1,325,457)
Future income tax benefit on share issue costs	–	73,584
Balance, December 31, 2001	**32,198,218**	**11,401,031**

(c) On February 15, 2000 the Corporation issued 140,000 common shares at a price of $0.50 per share for net proceeds of $70,000. The private placement included 70,000 share purchase warrants exercisable up to February 15, 2001 at a price of $0.60 per common share (Note 6(h)).

(d) On August 4, 2000 the Corporation issued 1,160,000 flow-through common shares through a private placement at a price of $0.50 per share for net proceeds of $553,249. Pursuant to a flow-through share agreement, the Corporation renounced $580,000 of income tax deductions in 2000 to the subscribers of these shares. At December 31, 2000 $580,000 has been spent on qualifying expenditures.

(e) On June 13, 2000, at the Corporation's Special and Annual Meeting of Shareholders, the shareholders approved a special resolution of the Corporation reducing the stated capital of the Corporation by $3,186,722, pursuant to the *Business Corporations Act* (Alberta).

(f) On October 25, 2000 the Corporation issued 4,000,000 common shares through a private placement at a price of $0.75 per share for net proceeds of $2,993,118.

(g) On December 22, 2000 the Corporation issued 2,000,000 flow-through common shares through a private placement at a price of $1.00 per share for net proceeds of $1,996,943. Pursuant to a flow-through share agreement, the Corporation renounced $2,000,000 of income tax deductions in 2000 to the subscribers of these shares. At December 31, 2001 and 2000, $1,972,322 and $27,678 respectively has been spent on qualifying expenditures.

(h) On February 15, 2001 a total of 70,000 share purchase warrants were exercised at an exercise price of $0.60 per warrant, for net proceeds of $42,000. As a result 70,000 common shares of the Corporation were issued to the holders of these warrants.

(i) On June 1, 2001 a total of 75,000 stock options were exercised at an exercise price of $0.29 per share, for net proceeds of $21,750. As a result 75,000 common shares of the Corporation were issued to the holders of these stock options.

(j) On July 11, 2001 the Corporation issued 3,205,443 flow-through common shares through a private placement at a price of $0.90 per share for net proceeds of $2,713,987. Pursuant to a flow-through share agreement, the Corporation renounced $2,884,899 of income tax deductions in 2001 to the subscribers of these shares. At December 31, 2001 $1,222,341 has been spent on qualifying expenditures.

(k) On December 14, 2001 the Corporation cleared a private placement of 12,823,000 common shares at a price of $0.20 per share for net proceeds of $2,561,185.

(l) Subsequent to December 31, 2001, on February 14, 2002 the Corporation issued 24,999,999 common shares through a private placement at a price of $0.30 per share for gross proceeds of approximately $7,500,000. Net proceeds are estimated to be approximately $7,000,000.

7. STOCK OPTIONS

A summary of the changes during the year ended December 31, 2001 and the Corporation's outstanding options as at December 31, 2001 is presented below:

	Number	Weighted Average Exercise Price
Outstanding, December 31, 1999	565,000	$0.33
Granted	1,106,250	$0.85
Exercised	(350,000)	$0.32
Cancelled	(15,000)	$0.29
Outstanding, December 31, 2000	1,306,250	$0.77
Granted	200,000	$0.62
Exercised	(75,000)	$0.29
Repurchased and/or cancelled	(145,000)	$0.37
Outstanding, December 31, 2001	**1,286,250**	**$0.82**

Date of Grant	Number Outstanding at December 31, 2001	Date of Expiry	Weighted Average Exercise Price	Number Exercisable December 31, 2001
Jun 13, 2000	37,500	Aug 01, 2005	$0.40	12,500
Sep 5, 2000	18,750	Sep 05, 2005	$0.60	6,250
Sep 20, 2000	905,000	Sep 20, 2005	$0.85	301,667
Oct 30, 2000	125,000	Oct 30, 2005	$1.04	41,667
May 4, 2001	200,000	May 04, 2006	$0.62	–
	1,286,250		$0.82	362,084

8. INCOME AND OTHER TAXES

As at December 31, 2001 the Corporation has exploration and development costs and undepreciated capital costs available for deduction against future taxable income of approximately $8,134,616 (2000 - $4,217,000). In addition, at December 31, 2001 the Corporation has non-capital losses carried forward for income tax purposes of approximately $3,028,000 (2000 - $2,229,000). These non-capital losses are available for deduction against future years' taxable income and will begin to expire in 2001.

Approximately $127,000 and $40,000 will expire in the 2001 and 2002 taxation years, respectively, if the Corporation is unable to claim these non-capital losses. No benefit from these non-capital losses has been recognized in the financial statements.

The provision for income taxes differs from the result, which would be obtained by applying the combined Canadian Federal and Provincial income tax rate of approximately 42.21% to the loss before taxes. The difference results from the following items:

	2001 $	2000 $
Computed expected income tax recovery	**(4,326,758)**	(492,346)
Increase (decrease) in taxes resulting from:		
Non-deductible crown charges	**44,213**	44,678
Non-deductible expenses	**1,355**	1,057
Resource allowance	**36,696**	27,735
Alberta royalty tax credits	**(3,378)**	(8,148)
Unrecognized benefit of non-capital losses and other	**2,995,999**	17,377
Future income tax recovery	**(1,251,873)**	(409,647)

The Corporation has paid $67,200 (2000 - $Nil) in current taxes relating to Part XII.6 tax. Part XII.6 tax is calculated based upon when previously renounced resource expenditures are actually incurred by the Corporation.

9. COMMITMENTS AND CONTINGENCIES

The Corporation is committed under two operating leases for its premises with the following aggregate minimum lease payments to the expiration of the leases on various dates, the latest being September 28, 2003.

	$
2002	146,800
2003	115,560

The Corporation has sold forward 150 bbls/d of heavy oil from January 1, 2002 to December 31, 2002 at a WTI price of $36.94 Canadian. A Lloyd Blend at Hardisty differential of $US 9.60 was sold forward for the same 150 bbls/d for the same period.

The Corporation has sold forward 50 bbls/d of heavy oil from January 1, 2002 to December 31, 2002 at a WTI price of $32.21 Canadian. A Lloyd Blend at Hardisty differential of $US 7.20 was sold forward for the same 50 bbls/d for the same period.

10. SUPPLEMENTARY CASH FLOW INFORMATION

Interest paid on a cash basis for the current year was $21,016 (2000 - $91,868). Taxes paid on a cash basis for the current year were $67,200 (2000 - $Nil). (See Note 8)

The following table details the components of non-cash working capital provided by (used in) operations.

	2001 $	2000 $
Accounts receivable	**10,749**	(484,039)
Marketable securities	**5,623**	–
Deposits and prepaid expenses	**28,411**	(257,738)
Accounts payable and accrued liabilities	**785,216**	194,731
Current portion of long-term debt	**(39,959)**	39,959
	790,040	(507,087)

11. SUBSEQUENT EVENTS

Central Alberta Acquisition of Petroleum and Natural Gas Properties

On February 28, 2002 the Corporation closed a $12 million acquisition of light oil and natural gas producing properties in Central Alberta. The acquisition had an effective date of November 1, 2001 for the purpose of determining the final purchase price. The Corporation will record production volumes, revenue and expenses only from March 1, 2002 forward.

In conjunction with this acquisition some miscellaneous interests were removed from the acquisition by the exercise of rights of first refusal by third parties. Also, the Corporation concurrently resold some additional miscellaneous properties acquired in this transaction. As a result of the above and the effective date adjustment, the Corporation is estimating a net acquisition price of approximately $10 million. In order to finance the acquisition the Corporation issued 24,999,999 common shares pursuant to a private placement on February 14, 2002 (see Note 6(l)) and increased its revolving production loan facility (see Note 5).

12. COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's presentation.

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Vice President

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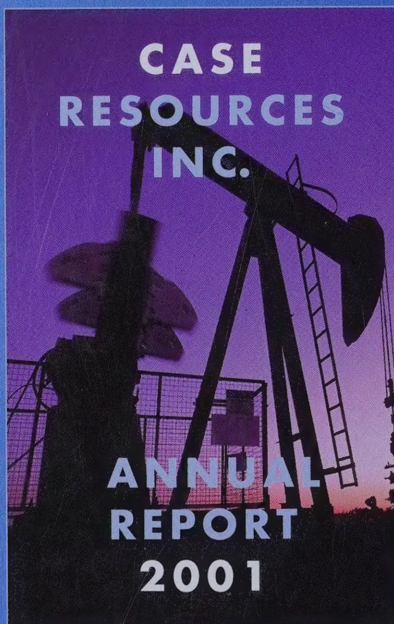

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